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Progress Energy

POSTED 09/28/05

September 28, 2005

Mr. Charles Terreni
Chief Clerk/Administrator
Public Service Commission of South Carolina
P. O. Drawer 11649
Columbia, South Carolina 29211

Re: Docket No. 2005-191-E

Dear Mr. Terreni:

Enclosed for filing are the original and twenty-five copies of the testimony of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. witness Samuel S. Waters.

If you have any questions or concerns, please do not hesitate to contact the undersigned.

Very truly yours,

Len S. Anthony
Deputy General Counsel – Regulatory Affairs

LSA:mhm

Enclosures

cc: All parties of record

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DATE: HK DBR
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SC PUBLIC SERVICE COMMISSION

Progress Energy Service Company, LLC
P.O. Box 1551
Raleigh, NC 27602

PROGRESS ENERGY CAROLINAS, INC.

DOCKET NO. 2005-191-E

DIRECT TESTIMONY OF

SAMUEL S. WATERS

Q. Please state your name, employer, and business address.

A. My name is Samuel S. Waters and I am employed by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC). My business address is 410 S. Wilmington Street, Raleigh, North Carolina, 27602.

Q. Please tell us your position with PEC and describe your duties and responsibilities in that position.

A. I am Manager of Resource Planning for PEC and Progress Energy Florida, Inc., the two regulated public utilities owned by Progress Energy, Inc. I am responsible for directing the resource planning process for both companies. The resource planning process is an integrated approach to finding the most cost-effective alternatives to meet each company's obligation to serve, in terms of long-term price and reliability. We examine both supply-side and demand-side resources available and potentially available to each Company over its planning horizon, relative to the Company's load forecasts. In my capacity as Manager of Resource Planning, I oversaw the completion of the Company's most recent Integrated Resource Planning (IRP) document filed with the Commission in June 2005.

Q. Please summarize your educational background and employment experience.

A. I graduated from Duke University with a Bachelor of Science degree in Engineering in 1974. From 1974 to 1985, I was employed by the Advanced Systems Technology

Division of the Westinghouse Electric Corporation as a consultant in the areas of transmission planning and power system analysis. While employed by Westinghouse, I earned a Masters Degree in Electrical Engineering from Carnegie-Mellon University.

I joined the System Planning department of Florida Power & Light Company (FPL) in 1985, working in the generation planning area. I became Supervisor of Resource Planning in 1986, and subsequently Manager of Integrated Resource Planning in 1987, a position I held until 1993. In late, 1993, I assumed the position of Director, Market Planning, where I was responsible for oversight of the regulatory activities of FPL's Marketing Department, as well as tracking of marketing-related trends and developments.

In 1994, I became Director of Regulatory Affairs Coordination, where I was responsible for management of FPL's regulatory filings with the FPSC and the Federal Energy Regulatory Commission (FERC). In 2000, I returned to FPL's Resource Planning Department as Director.

I assumed my current position with Progress Energy in January of 2004. I am a registered Professional Engineer in the states of Pennsylvania and Florida, and a Senior Member of the Institute of Electrical and Electronics Engineers, Inc. (IEEE).

Q. What is the purpose of your testimony in this proceeding?

A. My testimony will present a brief overview of PEC's integrated resource planning (IRP) process, focusing on the key elements of the analytical approach, but more importantly, emphasizing the customer-focused nature of resource planning. I will include in my discussion a review of process objectives, the tools used to identify the most cost-effective resource plan, the key inputs and drivers that influence plan development, the

alternatives considered to meet future customer needs, and the steps taken to thoroughly analyze the robustness of the final plan. Following my discussion of the process, I will discuss how the use of a Request for Proposals (RFP) fits into the overall process and the role an RFP should play in ensuring that customers are provided an adequate, cost-effective source of electricity.

Q. How would you define Integrated Resource Planning?

A. I would define Integrated Resource Planning as the process of determining the most cost-effective mix of resources, both supply- and demand-side, that will serve customers' demand and energy needs in a reliable manner. There are two points I would like to emphasize in this definition, first, that the process focuses on customer needs, and second, that reliability is the major driver in determining the final plan or, put another way, reliability comes first, then cost. I will discuss these points in greater detail as I describe the process.

Q. What are the basic steps involved in the IRP process?

A. The quantitative part of the process basically consists of three steps: determination of the amount and timing of resource needs, evaluation of alternatives to identify the feasible options to meet the identified need, and detailed economic analysis to identify the most cost-effective resource plan. I use here the term cost-effective rather than "least cost", because I believe it is more descriptive of the economic evaluation process. I will elaborate on this point later in my testimony. Following these quantitative steps, the final resource plan is qualitatively evaluated against additional criteria that need to be considered before final plan implementation is initiated.

Q. How does PEC determine the amount and timing of its resource needs?

A. In very basic terms, the amount of existing resources, including generation assets and purchased power under contract, is compared to the expected peak demand from customers, less any reduction available from load management or conservation programs. Simply put, supply must be greater than demand. To ensure that the supply of electricity is reliable, the amount of supply must be adequate to meet customers' maximum expected demand for electricity in any given hour of the year. PEC determines the adequacy of the supply system using a reliability criterion of 0.1 days per year Loss of Load Expectation (LOLE), sometimes referred to as Loss of Load Probability, or LOLP. The criterion is also called "one day in ten years", and is commonly used throughout the electric utility industry. Basically, this means that PEC plans it system in such a manner that in only one day in ten years is it probable that PEC will not have the resources necessary to meet the electricity needs of its customers. On the PEC system, this level of LOLE translates to a reserve margin of approximately 12-15%.

In application, LOLE analysis looks at the expected peak demand for each of the 365 days in a year, and calculates the probability that the demand will exceed expected available resources. The resources available on any given day are determined by maintenance schedules and the expected forced outage rate (FOR) for each generating unit. The daily probabilities are summed over the year and compared to the standard of 0.1 days. If the sum of these probabilities exceeds 0.1 for the year, additional resources, or demand reductions, are needed. Typically, these calculations are performed over a ten to twenty year planning horizon, and the timing of resource needs can be identified over that period.

Q. How is the reliability criterion of 0.1 days per year established?

A. This criterion, or 1 day in 10 years, has been accepted throughout the utility industry for a number of years. Its acceptance is based on utility experience, and it represents a reasonable balance between cost and reliability, in other words, it does not result in an "overbuilt" system with excessive costs, nor does it result in a system that is vulnerable to power outages due to inadequate supply. This criterion has been found to be acceptable to cover a wide range of system uncertainties and contingencies, including load uncertainty due to weather and customer growth, generator outages and deratings, capacity support available through interconnections with other utilities, transmission outages and uncertainty over economic conditions.

Q. Does the cost of new alternatives influence the determination of the amount of resources needed?

A. No. The determination at this point identifies how much capacity is needed to maintain reliability, without consideration of the costs of alternatives. As I stated above, the reliability criterion was established to balance overall system costs to customers with adequacy of supply. Having established that criterion, the IRP process proceeds first to meet the adequacy target, then minimize costs. This is what led me to state earlier that reliability comes first, then cost.

Q. How does PEC determine the system LOLE?

A. Using system projections of customer demand, which is obviously a key input into this step, we run a model called the Tieline and Generation Reliability (TIGER) model, which is capable of modeling the forecasted supply system and daily demands in detail. The

model calculates both monthly and annual reliability figures, and is capable of accounting for the ties that PEC has to neighboring utilities, which help to increase system reliability.

Q. Once you have identified the need for a new resource, what alternatives are considered to meet that need?

A. At this stage, there is a long list of potential alternatives available to meet any resource needs, including both demand- and supply-side options. Demand-side alternatives might include conservation programs, direct load management programs, curtailable or interruptible rate offerings, or voltage reduction, for example. Supply side alternatives would include conventional generating options like combustion turbines, combined cycle and pulverized coal units, as well as developing technologies like integrated coal-gasification combined cycle (IGCC), fluidized bed coal and advanced nuclear units. Renewable alternatives such as biomass, solar and wind energy are also considered. Alternatives may also exist within each classification, such as various competing combustion turbine technologies.

From this comprehensive list, a preliminary economic comparison is done to develop a short list of viable alternatives that will be analyzed in a more detailed economic evaluation. This preliminary economic evaluation compares like alternatives, such as the competing combustion turbine technologies mentioned above, on a levelized or busbar cost basis. This technique, known as busbar or screening curves, compares the cost of capital, fuel and non-fuel operation and maintenance expense ("O&M") of the alternatives over a range of capacity factors, without consideration of how the alternative might operate as part of the system and impact total fuel and O&M costs. Using this approach, the list of viable combustion turbines might be reduced to one, just as the

number of competing coal alternatives might be reduced, etc. The end result is a manageable list of alternatives that would be retained for the final analysis.

Q. Would power purchases be considered at this point in the IRP process?

A. No. The process I am describing is used to identify the most cost-effective resource that PEC would pursue, absent any power purchases. Once this benchmark cost is identified, potential purchases are compared to determine if a purchase is more cost effective. I will discuss how this can be done later in my testimony.

Q. Following the identification of the viable resource alternatives, how is the detailed economic analysis performed?

A. All of the viable resource alternatives are compared by creating alternative resource plans, consisting of combinations of the alternatives that meet system reliability targets, as previously discussed, and comparing these competing resource plans on a total system revenue requirements basis, which includes the capital cost of unit additions, incremental O&M expense of any additions, and the total system fuel costs, which includes the fuel cost of the new additions. The comparison is done on a cumulative present value of revenue requirements (CPVRR) basis which allows a comparison of the total cost to customers over the planning horizon of twenty years or more. Note that the comparison is based on the costs to customers, and, as was the case with reliability calculations, it is concern for the customer that is the driver of the resource plan results.

Q. Even with a short list of competing options, is the number of alternative resource plans relatively large?

A. Yes. In the past, computer and model limitations meant that IRP studies required that a number of unique competing resource plans be identified for entry into a model that

calculated the cost of each plan individually. PEC now uses a tool called STRATEGIST, which is a dynamic program, capable of creating all combinations of resource alternatives and calculating the CPVRR of each competing plan, identifying the plan with the lowest CPVRR and ranking other plans in order of cost. This tool eliminates the possibility that a combination of alternatives with lower costs might not be considered.

Q. Does STRATEGIST identify the most cost-effective resource plan?

A. No, there is more to do in completing the plan. This is one place I make the distinction between least cost and most cost-effective plans. STRATEGIST identifies the plan that has the lowest CPVRR over a specified time horizon. For example, STRATEGIST might identify a plan consisting of Alternative A as having the lowest CPVRR in year 40. However, it is possible that a plan consisting of Alternative B had a lower CPVRR for years 1 through 39, but crossed over Alternative A in year 40. Which plan is truly least cost? There are arguments to be made either way, but I believe that Alternative B should be considered as the most cost-effective alternative in this example, because it provides lower costs in the earlier years of its life, and it is in these earlier years that the assumptions upon which the analysis is based present less uncertainty. The point here is that there is some judgment to be applied in determining the most cost-effective plan.

Q. What remains to be done in the detailed economic analysis?

A. Because the STRATEGIST model must simplify the representation of the generating system to compare the very large number of alternative plans, a more detailed modeling of system operation may be required. As an example of why this may be needed, consider that the economic modeling must account for system air emissions in calculating system fuel and O&M costs. This is due to the fact that environmental

regulations, such as the Clean Smokestacks Law in North Carolina, and the Clean Air Interstate Rule (CAIR), at the federal level, place caps on the amount of Nitrogen Oxide ("NOx") and Sulfur Dioxide ("SO2") that may be emitted in any given year. The existence of these caps may influence system dispatch, as units that may be lower cost, but have higher emission rates, may have their outputs adjusted to account for these characteristics. The STRATEGIST model approximates these effects, but a more detailed examination is required, and for this purpose, PEC runs the Prosym model to evaluate system production costs in more detail. This final, detailed analysis ensures that the plan will meet the reliability, economic and environmental objectives that have been identified.

Q. Is there any more quantitative analysis in this detailed economic step?

A. Yes. The remaining effort focuses on determining how the plan identified to this point as the most cost-effective alternative performs under variations in the key assumptions, such as changes in fuel price forecasts, or potential changes in environmental regulation, such as the implementation of a carbon tax or more restrictive air emission caps. These sensitivity analyses provide additional insight as to how robust a resource plan is as conditions change, knowing that they most certainly will change from the base assumptions used in the planning process. They also provide some bases for the qualitative considerations that follow.

Q. What qualitative analyses are performed after identification of a cost-effective resource plan?

A. While the quantitative portion of the process may identify a preferred resource plan, there are still other considerations, which may be difficult to put in quantitative terms, but must

be considered. For example, consider fuel diversity. A balanced resource portfolio, utilizing a number of different fuel sources, offers some protection against volatility in the price of any single fuel, and protection against the unavailability or disruption of any fuel source. It is difficult to put a monetary value on this protection, just as it is difficult to put a value on having insurance, but in considering competing resource alternatives, some weight must be placed on this factor.

Another example of a qualitative factor to consider is technological risk. While best estimates of the cost of a technology might lead to the conclusion that it is a cost-effective alternative, lack of operating experience might be a concern that overrides the economic result. Other examples, although not all-inclusive, of qualitative considerations are the ability of a plan to meet unforeseen environmental regulations, or the ability of a technology to adapt to changing conditions. IRP is not a matter of identifying a plan that meets only reliability and cost considerations. The final plan must be the one that can be expected to meet customers' needs over a variety of conditions.

Q. Once this plan is identified, does this complete the process and lead to the construction of new capacity on the PEC system?

A. No. Because the goal of the IRP process is to meet customer needs for a reliable supply of electricity in the most cost-effective manner possible, the plan that has been identified now serves as a benchmark against which any market opportunities may be measured. Before proceeding with a self-build option, it is in the best interest of customers to consider whether there are any purchased power alternatives available that might maintain the system reliability level in a more cost-effective manner. This is where a

Request for Proposals (RFP) might provide a valuable means of identifying market opportunities.

Q. Should an RFP be required at this point in the process?

A. No. While an RFP can be a useful tool in soliciting potential power supplies and ultimately demonstrating that a final decision is the most cost-effective alternative, requiring utilities to issue an RFP in every instance where they have a need for a new resource is unnecessary, and in some instances, possibly harmful. I can give examples from my own experience that demonstrate how requiring an RFP might jeopardize reliability and the pursuit of lowest cost resources for the customer.

As my first example, consider the case of a utility faced with serving a major new customer. This customer's load may result from the state's economic development activities or other reasons, but the new load would be considered to be substantial and require that the utility add resources or face violating its reliability criterion. This new load, which might represent a new factory or service center, will be added within three years, and since the utility must serve the new load, the only alternative available within a three year time frame might be to add combustion turbines to the system. Given that an RFP process takes from 9 to 12 months to complete, allowing time to create and distribute the RFP, allow for vendor responses and fully analyze the submittals, there would not be enough time to go through the process and meet the lead time requirements for adding the new units. I don't think anyone would suggest that an RFP would be in the customers' best interest if it resulted in a supply shortage.

Another example is where a utility becomes aware of a unique opportunity that provides an obvious benefit to customers, and for which there is likely to be a significant

competitive market to obtain the capacity offered. There are several ways this might occur, but one example might be when a utility has built a new generating unit, and its load has not grown sufficiently to fully utilize the resource, or possibly this new resource was not allowed in rate base by another state's regulatory body. This utility has an incentive to sell the capacity for some term, and it may be uniquely attractive to PEC because of its fuel characteristics or pricing. I don't believe that anyone would suggest that PEC should be required to issue an RFP before buying from this available resource.

Q. Are you indicating that PEC will not issue an RFP before proceeding with capacity decisions?

A. No, not at all. I am simply suggesting that an RFP is not always in the best interests of customers. I think it should be remembered that PEC operates in a regulated environment, and every decision is subject to full scrutiny by this Commission. We are well aware that prior to PEC constructing a new generating resource we must obtain the approval of either the South Carolina or North Carolina Commission. In addition, before we can recover the cost of a new resource we must fully justify the costs. Issuance of an RFP is, as I previously stated, a good way of demonstrating to the Commission that a capacity decision is prudent and cost-effective, but it is not the only way. As a general policy, PEC intends to issue RFPs for its identified capacity needs, and it would be an exception to not issue one. In fact, PEC recently issued an RFP for its identified capacity need in its Western Region, and did not receive a single response to the solicitation. This result certainly does not indicate that there is a thriving market waiting to be unleashed if RFPs are required in all cases, and it certainly argues against the need to make any changes to the current process employed by utilities to obtain capacity, which

allows the flexibility to issue RFPs when they provide benefit, and pursue other alternatives when they would not.

Q. One of the arguments made for requiring RFPs is that it will stimulate competition and result in lower costs to customers. Do you agree?

A. Since I am not an economist, I can't address the philosophical or theoretical argument, but I can say that the implication of this argument is that we, the utility planners, are woefully ignorant of market conditions, purchase opportunities, and the costs of developing new generation, and I would strongly disagree with this implication, for several reasons. First, our capacity needs are not secret. We file our resource plans with this Commission as well as in North Carolina, indicating how much capacity is needed and when. Therefore, I would expect anyone that wants to sell us capacity would have a good idea of what we need. Second, we are in constant pursuit of opportunities that will save money for customers. We make transactions on both a short-term and long-term basis when they provide such savings, and we would be imprudent not to pursue them on an ongoing basis. Third, we have issued RFPs, as I mentioned before, and the results of those efforts also give us good market information. As to the costs of new generation, there is a fundamental question of why it should be expected that any provider can construct a new unit at a lower cost than PEC. Considering combustion turbine technology, for example, PEC solicits the same vendors for the same technologies that any other power provider would solicit. PEC hires the same labor force, faces the same transmission integration costs and goes to the same financial market as other suppliers. Issuance of an RFP does not, in itself, provide any savings to PEC customers. Savings are provided by the continuing efforts of PEC to identify unique opportunities in existing

markets, and an RFP may be one tool used as part of that ongoing effort, but it is not the only tool.

Q. Are mandatory RFP requirements necessary to cause utilities to consider power purchases from other suppliers?

A. Absolutely not. PEC has a long history of making prudent cost-effective power purchases in lieu of self-building new generation. Examples include a twenty year deal for baseload coal-fired generation from another utility and a twenty year purchase from the Broad River facility here in South Carolina. No mandated RFP regulatory requirement is necessary for PEC to continue to utilize similar opportunities in the future.

Q. Do you believe that there is a need to introduce rules requiring utilities to issue an RFP before finalizing any capacity decision?

A. No. The current system, with its existing checks and balances, provides adequate protection for customers. Every decision we make is subject to Commission review, and we understand fully that it is our burden to demonstrate that we have made the appropriate decision. PEC has issued RFPs for capacity needs in the past and intends to continue use of the RFP process when appropriate. However, as I have discussed, there may be circumstances where issuance of an RFP may not be appropriate and, in fact, may be detrimental. A mandatory RFP is the first step in removing responsibility for capacity decisions without removing the corresponding accountability and an invitation to litigious disputes over every capacity decision. The utility alone is accountable for capacity decisions, and it is only the utility that can be called before this Commission to explain resource decisions and the performance of the supply system that results. Our goal in the IRP process is to act in the best interest of customers, and that is what I

believe should be the goal in considering whether an RFP should be required. The fundamental question that should be weighed is whether or not such a requirement would result in customer benefits, and from where those benefits would come. The competitive interests of vendors should play no part in such a consideration. If, as I believe, there are no examples that can be brought forward showing that utility decisions made to date are flawed, then that suggests that no change is needed to the current process. Because this ultimate accountability rests with the utility, I believe that the responsibility for resource decisions, and the methodology employed to make those decisions, should remain with the utility.

Q. Does this conclude your testimony?

A. Yes.

STATE OF SOUTH CAROLINA
BEFORE THE PUBLIC SERVICE COMMISSION

DOCKET NO. 2005-191-E

In the Matter of: GENERIC PROCEEDING TO EXPLORE A FORMAL REQUEST FOR PROPOSAL FOR UTILITIES THAT ARE CONSIDERING ALTERNATIVES FOR ADDING GENERATING

Application of Progress Energy Carolinas, Inc. for Permission to Sell Land that is no Longer Needed to Provide Utility Service)

CERTIFICATE OF SERVICE

This is to certify that I, Len Anthony, an employee of Progress Energy Service Company has served a copy of the direct testimony of Progress Energy Carolinas, Inc.'s on all parties of record either by hand delivery or by depositing said copy in the United States mail, postage prepaid, addressed as follows this the 28th day of September, 2005:

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